Independent Petroleum Association of America
Domestic Petroleum Council

July 31, 1998

BY FACSIMILE, E-MAIL, AND CERTIFIED MAIL

David S. Guzy
Chief, Rules and Publication Staff
Royalty Management Program
Minerals Management Service
P.O. Box 25165, MS 3021
Denver, Colorado 80225-0165

Re: Further Supplementary Proposed Rule on Crude Oil Valuation, 63 Fed Reg. 38355 (July 16, 1998)

Dear Mr. Guzy:

The Independent Petroleum Association of America ("IPAA") and the Domestic Petroleum Council ("DPC") welcome the opportunity to comment on the Minerals Management Service's ("MMS") further supplementary proposed rule.

During the July 22, 1998, meeting among Senators, MMS officials, and producer CEOs, the MMS representatives seemed surprised that independent producers remain engaged in the debate over crude oil valuation. MMS appears to have misunderstood the independents' message which we hope to clarify through these comments. Lest there be any doubt, IPAA and DPC cannot support this rule The associations have endorsed the Industry Recommended Improvements to MMS Oil Valuation Proposed Regulations ("CEO Proposal"), (Attachment 1), presented during the July 22nd meeting and will also address MMS's written response ("MMS Response"), (Attachment 2), in these comments.[1]

While we appreciate the agency's efforts to address industry concerns, IPAA and DPC members are disappointed with this most recent proposal. As proposed, the rule violates the terms of existing leases by moving the point of royalty valuation downstream from the lease and it creates a great deal of uncertainty for lessees, as explained more fully below. Many of the persistent conflicts between MMS and industry over crude oil valuation would be resolved if the agency were to adopt a benchmark system based on lease market values.

---

[1] To provide a more technical analysis of these issues, IPAA and DPC also incorporate by reference the comments on this rule prepared by the Barents Group.

During the course of this rulemaking process, IPAA and DPC have developed and refined a benchmark system based on lease market values that would apply to all federal oil sold under non-arm's-length arrangements.[2] MMS has refused, however, without reasonable justification, to adopt such a system. The current proposal limits the use of lease market benchmarks to integrated producer-refiners and is only available in the Rockies. All other producers with affiliates will be forced to net back from the first arm's-length sale whereever it occurs. If a downstream market is where the first arm's-length sale occurs, producers should be able to deduct all costs, including marketing, of getting the product there. The associations reemphasize that independent producers with affiliates should be permitted to use a weighted volume average for their purchases or sales at or near the lease in all regions, and/or should be allowed to tender their oil from any federal lease.

The agency has said that benchmarks cannot be used on a national basis because of an alleged lack of reliable arm's-length sales information. MMS has further stated that it would consider valuation benchmarks in limited situations in the Rockies because there is no publicly available, reliable indicator of market value in that region. But if benchmarks are an appropriate valuation system in the Rockies, we fail to understand why they cannot be implemented on a national basis. Producers outside the Rockies should not be denied the use of benchmarks simply because MMS believes reliable arm's-length sales information is not available for every field. If a captive market exists, there are not likely to be significant quantities of arm's-length activities, and the benchmarks will not apply.

With respect to gathering and transportation, IPAA and DPC commend the MMS for moving in the right direction by reopening the dialogue on these issues. We also appreciate the agency's return to the original definition of affiliate, but remain concerned that many of the issues associated with affiliates have not been resolved, as explained more fully below.

---

2 IPAA May 15, 1997, Comments at 10-11 (offering to "work with MMS to develop appropriate criteria for interpreting market information under the new, improved benchmark system"); IPAA and Domestic Petroleum Council August 1, 1997, Comments, Exhibit 4 (details of proposed Oil Valuation Benchmark System consisting of 5 benchmarks); IPAA October 31, 1997, Comments at 4 & Attachment 1 (introducing modified benchmark system consisting of 3 revised valuation principles).

SPECIFIC COMMENTS

Arm's-Length Contracts

1. Breach of Duty to Market

July 16, 1998, Proposed Rule

IPAA and DPC are troubled by MMS's elaboration on the duty to market for several reasons. First, noting that the duty has been in the regulations for over ten years, MMS continues to claim that the duty to market "has never been used to 'second-guess' a lessee's marketing decisions." 63 Fed. Reg. 38356. This is simply not true. In two recent departmental decisions, MMS rejected a lessee's arm's-length gross proceeds, demanding that the lessee pay royalty on the price received by the unaffiliated purchaser when the purchaser resold the oil or gas downstream.[3]

We have called this issue to MMS's attention before in comments and by IPAA's filing of an amicus curiae brief in *Taylor Energy, Co.* The agency, however, has never explained why these cases do not constitute second guessing of a producer's arm's-length sales at the lease. Yet they represent precisely the behavior independent producers have objected to throughout this rulemaking.

---

[3] In *Amerac Energy Corp.*, MMS-93-0868-OCS (1996), *appeal pending*, an MMS Director's decision, MMS used the duty to market to attack arm's-length transactions between the producer and refiner-marketer. Amerac sold oil at the lease under an arm's-length contract at posted prices. Separately, the parties agreed that Amerac would receive 50% of net profits from the refiner-marketer's hedging activities and resale of the production. Amerac paid royalties on its gross proceeds: the posted price plus its share of the net profits. Nonetheless, MMS second-guessed Amerac's gross proceeds and is now seeking royalties on the refiner-marketer's share of the profits as well.

The most recent example of MMS's second guessing is *Taylor Energy Co.*, 143 IBLA 80 (1998), *petition for reconsideration pending*, issued by the Interior Board of Land Appeals. Taylor stopped selling gas at its leases to a pipeline and entered a contract to sell its gas at the lease to a marketing company. Instead of accepting a fixed price for the gas at the lease, Taylor negotiated to obtain a price for the gas which was 97% of the average price received by the marketing company for reselling downstream, an amount which proved to be approximately $0.10 per MMBtu higher than the amount received previously from the pipeline. Taylor paid royalties on its gross proceeds, which were 97% of what its purchaser obtained downstream. Even though MMS had accepted the lower price from the pipeline as fair market value, MMS second guessed Taylor's gross proceeds and claimed royalties on 100% of what the marketing company received downstream on resale, again citing the duty to market.

The associations' second concern is that the additional regulatory language creates uncertainty and gives MMS even more discretion than it previously had. Rather than establishing concrete, objective standards against which to judge a "breach of [the] duty to market," MMS promises not to dispute marketing decisions "made reasonably and in good faith." It will only question circumstances in which a lessee or his affiliate "inappropriately sells its oil at a price substantially below market value." 63 Fed. Reg. 38357. While MMS's intent in the preamble was to "clarify that the lessee's duty to market does not mean that MMS will second-guess a company's marketing decisions," the additional language in the regulation itself actually provides even more subjective opportunities for MMS to second guess that an arm's-length transaction is not market value. Independents remain concerned about the potential for second guessing - if MMS rejects a producer's gross proceeds based on the duty to market, he will be forced to value production using index prices. This affects every independent who produces federal crude oil.

The agency has expressed a reluctance to reverse legal precedent on this issue, however, no court has ever affirmed that a duty to market even exists. MMS's only legitimate concern is with arm's-length transactions that are so substantially below other arm's-length prices for like-quality oil at the lease that they raise a concern over the producer's good faith or the existence of consideration outside the four corners of the contract. Those concerns are already adequately addressed in the provisions of current 30 C.F.R. § 206.102(b)(1)(iii) concerning "misconduct by or between [the] contracting parties," thereby negating the need for regulatory language regarding breach of the duty to market.

Finally, given the agency's reluctance to rely on lease market values for non-arm's-length transactions because of the supposed unavailability of such information, IPAA and DPC has significant concerns about how MMS will determine that a price is "substantially below market value." Lease market benchmarks are essential to the implementation of this proposed language.

MMS Response

Following the July 22nd meeting, MMS made reference to retaining the duty to market language contained in existing regulations. The associations would support retaining the 1988 regulatory language, including the existing definition of gross proceeds.

2. Multiple Exchange Agreements

July 16, 1998, Proposed Rule

MMS correctly observes in the preamble that workshop participants asked for the option of valuing exchanged oil using lease-market benchmarks or the lessee's resale price minus an exchange differential no matter how many exchanges occurred. The agency's response was to impose mandatory tracing on all producers who do not refine and who exchange oil under one or more arm's-length agreements. 63 Fed. Reg. 6127 (Feb. 6, 1998) (proposed 30 C.F.R. § 206.102(c)). Indeed, many producers objected to the difficult and, in some cases, impossible task of tracing back from the gross proceeds under the first arm's-length contract in complex situations. Evidently MMS missed the point - independent producers who do exchange more than once, particularly offshore, still want the option of using gross proceeds in situations where tracing would be simple. Rather than giving them the option, MMS has returned to the July 3, 1997, "first-exchange" rule which puts many independents back on index price valuation.

Because industry complained about mandatory tracing in prior comments and in a February 25, 1998, IPAA press release, MMS took away the multiple exchange rule. This does not make sense. All producers are asking for is a choice. In any event, if MMS were to adopt the benchmark system proposed by the associations, i.e., allow independents to employ a weighted volume average of their arm's-length sales or purchases at or near the lease, and/or allow tendering, the exchange issue would disappear.

MMS Response

The agency has asked industry to choose from among its July 1998, February 1998, and July 1997 proposals on this issue. While MMS's July 1997 proposal represents the best of the three options, it too falls short. The July 1997 proposal gives lessees the option of valuing exchanged oil using either 1) gross proceeds from the first arm's-length sale after exchange(s), or 2) index pricing. The fundamental flaw in this proposal is that it lacks an intermediate benchmark permitting valuation based on a weighted volume average of the lessee's arm's-length sales, which includes tendering, or purchases at or near the lease. It is the addition of this benchmark that allows independents to look to their own business transactions in the vicinity of the lease, rather than being forced to chase the first arm's-length sales or rely on index.

The July 1998 "first-exchange" rule is unacceptable because producers who exchange more than once, even if at arm's-length each time, will be forced to use the index pricing method which may not reflect fair market value. The February 1988 is unacceptable because it requires every producer who exchanges to trace production to the first arm's-length sale which will be quite burdensome in some cases.

Non-Arm's-Length Contracts

1. Menu

In its written response, MMS rejects industry's menu approach because it will allegedly result in undervaluation and increase the complexity of the royalty valuation process. Setting aside issues such as significant quantities and other technical matters, the associations note that there is really no difference between industry's menu approach and the benchmark system MMS has proposed in the Rockies.

We remind the agency that as our menu has evolved, we have withdrawn posted prices and resolved data access issues. These concessions were made based on MMS's view that reliance on posted prices results in undervaluation and the fact that lessees do not have ready access to comparable sales information.

Moreover, the associations fail to see how implementing a menu approach for all federal leases will lead to litigation if industry and MMS can agree on a mutually acceptable process. IPAA and DPC reiterate our willingness to work with the agency to design a system that addresses MMS's concerns about difficulty in administration, complexity, access to data, and comparability. For example, the Form 2014 could be adjusted to provide additional information and thereby expedite the audit process. Other suggestions include requiring lessees to notify MMS prior to electing a valuation method. Once made, lessees would be bound by that election for a commercially reasonable time.

Finally, the three-region approach is itself cumbersome, (a point which MMS does not dispute), and should be abandoned.

During the July 22nd meeting, MMS officials emphasized that the benchmark system in the current regulations must be measured against a lessee's gross proceeds. The value of production for royalty purposes must be the higher of the applicable benchmark or gross proceeds from sales at the lease. It is signficant to note that benchmarks which determine the value of production at the lease can only logically be compared to gross proceeds at the lease. The current proposal, however, moves the royalty valuation point downstream <u>away from</u> the lease.

2. <u>Tendering</u>

IPAA and DPC disagree with MMS's assertion that tendering is an artificial market created for the purpose of royalty valuation. Where there are willing buyers and willing sellers for oil at the lease, there is a market value. Tendering is, indeed, a true measure of arm's-length activity in the area because actual barrels are made available for purchase to unaffiliated third parties.

3. <u>Comparable Arm's Length Transactions</u>

As stated above, IPAA and DPC have accommodated the access to data issue in their proposed benchmark valuation system. The associations urge MMS to allow producers to look to their own arm's-length purchases and sales, including tendering, at or near the lease. In this regard, the percentage of arm's-length purchases and sales need only be higher than the royalty rate to deter a lessee from undervaluing oil sold under a non-arm's-length agreement. A percentage that includes the royalty percentage plus a limited amount of the lessee's equity production is enough to constitute a "significant quantity." Design criteria like this ensure that this type of benchmark will only be used by a producer who has adequate arm's-length activity in a field.

4. Definition of Affiliate

IPAA and DPC previously urged MMS to, at a minimum, maintain the status quo with respect to presumptions of control among affiliates. While the associations appreciate this concession to retain the current definition of affiliate, MMS has still not addressed the more significant issues regarding non-arm's-length transactions.

If MMS does retain the current rebuttable presumptions of control, IPAA and DPC request that the agency clarify what constitutes control for purposes of the rule

Marketing Costs

In its written response, MMS rejected industry's request to claim an administrative fee when the starting point for valuation is away from the lease. Attempting to distinguish the fee it charges small refiners in the RIK program, MMS described that fee as covering the "administrative costs of billing and accounting," not marketing. The agency misunderstands industry's request. IPAA and DPC have previously offered cost figures expressed in a cents/barrel basis representing actual overhead and out-of-pocket expenses incurred when the royalty valuation point is downstream from the lease. These calculations do not include risk management or marketing - like MMS's fee, they cover the lessee's administrative costs of billing and accounting.

Transportation

In the attached Supplemental Comments (Attachment 3), IPAA and DPC analyze the issues raised by subsea completion technology. In both shallower OCS waters and the deepwater, this technology permits the development of significant oil and gas reserves which cannot be economically exploited under traditional methods requiring the construction and installation of single or multiple structures. It is safe and cost effective. However, the extent to which this technology will be employed by industry depends on the way the MMS responds to requests for transportation allowances for the movement - often over significant distances - of the produced oil and gas from the lease to the structure where separation and/or treatment occurs.

Unfortunately, the MMS has refused so far to grant requests for such allowances, having chosen to characterize these movements as "gathering." IPAA and DPC members believe such refusal constitutes arbitrary discrimination against producers seeking to utilize a beneficial technology and is inconsistent with the reasoned exercise of discretion. The MMS should take this opportunity to issue, on an expedited basis, an interpretive rule applicable to its existing regulations and, with retroactive effect, providing that a transportation allowance will be granted the lessee when production from a subsea completion is moved away from the lease to a structure where separation or treatment is performed. The allowance should be available for production moving from a subsea completion in any water depth.

Further, in addition to requesting the issuance of the foregoing interpretive rule, IPAA and DPC agree with the MMS that the regulations should be modified to contemplate subsea completion operations. Unfortunately, the comment period is so abbreviated that IPAA and DPC have been unable to receive member approval for specific proposed regulatory text. Were a further extension of time for comment on this matter to be provided, IPAA and DPC are confident that such text would receive membership approval and be provided to the MMS. IPAA and DPC appreciate the MMS's willingness to reconsider its position on an important matter of great interest to independent producers. Both associations look forward to the opportunity for further input.

Non-binding Guidance

MMS's most recent proposal does not contain a provision for binding valuation determinations. To promote stability and certainty, IPAA and DPC urge the Secretary or Assistant Secretary to delegate to an MMS official the authority to make a binding valuation determination, or issue a refusal to do so in writing. In either case, the decision would be final and appealable to the MMS Director.

CONCLUSION

In sum, independent producers regretfully cannot support this rule, but hope to continue discussions with MMS to further clarify our message. We are very interested in working with the agency to resolve the issues surrounding crude oil valuation. The comment period should be reextended so that industry, MMS, and states can cooperate in developing a benchmark system that allows producers to look to their own arm's-length purchases and sales, including tendering, for valuation. We note for the record, that a benchmark system is supported by the state of Wyoming. Adoption of this benchmark will resolve many of the disagreements that currently exist.

Sincerely,

William Whitsitt, President
Domestic Petroleum Council

Diemer True, Chairman
Land and Royalty Committee
Independent Petroleum Association of America

dc-9252

ATTACHMENT 1

Industry Recommended Improvements to MMS Oil Valuation Proposed Regulations

Arm's Length Contracts

MMS should continue to honor prices received by willing sellers from willing buyers (arm's length agreements) and not reject these prices due to multiple buy/sells or exchanges, or second guess these transactions.

Non-Arm's Length Contracts

The MMS should replace the proposed cumbersome, three-region approach with a menu of valuation benchmarks flexible enough to accommodate diverse transactional settings nationwide and arrive at a reasonable value of production at the lease. Such a menu should include:

- A viable tendering for sale program.
- Reliance on comparable arm's length transactions, including purchases, by a lessee, a lessee's affiliate, or other parties (if published) at or near the lease.
- A methodology to net back to the lease from an index or affiliate re-sales if deductions are provided that adequately account for factors that add value as crude oil moves downstream from the lease.

Duty to Market

Where the starting point for valuation is away from the lease, the MMS should allow lessees to claim an administrative fee -- similar to the fee MMS charges small refiners in its set aside program.

Transportation

Reasonable commercial value of transportation should be the basis for calculation of transportation allowances.

Actual payments made under tariffs should be acceptable.

For lines handling multiple shippers, the payments by non-affiliated third parties should be used. In the absence of third parties, payments for comparable service areas should be used.

With the use of a tendering for sale program, the sale at the lease eliminates the issue of a transportation deduction.

Non-binding Guidance

The MMS should simplify and clarify its valuation requirements as much as practicable.

MMS should maintain a process by which lessees can procure binding valuation determinations.

July 22, 1998

ATTACHMENT 2

Note: The following are MMS' preliminary responses to industry's comments received at the July 22, 1998, Senate meeting regarding MMS' proposed Federal oil valuation regulations. Pursuant to the Administrative Procedures Act, MMS cannot provide final decisions as long as the comment period on the proposed oil valuation rule is still open. All public comments must be received and reviewed before final decisions are made. MMS' final comments will be published in its final rule.

July 24, 1998

Summary of Industry Recommended Improvements to MMS Oil Valuation Proposed Regulations and MMS Responses Discussed at July 22, 1998, Senate Meeting

Arm's-Length Contracts

Industry Recommendation

MMS should continue to honor prices received by willing sellers from willing buyers (arm's length agreements) and not reject these prices due to multiple buy/sells or exchanges, or second guess these transactions.

MMS Response

- Gross proceeds received under an arm's-length contract is the royalty value and MMS will not second guess a company's marketing decisions.

Breach of Duty to Market

During the July 22 meeting, industry representatives stated that the language contained in the July 16, 1998, further supplementary proposed rule regarding MMS not second guessing marketing decisions added more confusion to the rule. MMS stated that the only purpose of the additional language was to clarify that this provision would not be used to routinely reject arm's-length contracts in response to industry comments. Industry thought the additional terms created uncertainty and requested that MMS remove that language and instead retain the language contained in the existing regulations.

Multiple Exchange Agreements

Some industry representatives objected to the July 16, 1998, proposal to require index pricing after two or more exchanges while others objected to the administrative burden of tracing multiple exchanges.

MMS has in the past expressed a willingness to go any of a number of directions on this issue. That is, in the final rule MMS could adopt either:

(1) the July 1998 proposal to use the "first-exchange" rule where value will be determined based on the arm's-length sale after a single arm's-length exchange, or

(2) the February 1998 proposal to expand gross proceeds valuation to include situations where the oil received in exchange is ultimately sold arm's-length, regardless of the number of arm's-length exchanges involved, or

(3) the July 1997 proposal that allowed the lessee the option of valuing exchanged oil using either 1) its gross proceeds under an arm's-length sale after the exchange(s) or 2) the index pricing method. That election would be for a 2-year period and the lessee must value all oil production disposed of under all of their arm's-length exchange agreements in the same manner.

In its written comments on the July 16, 1998, further supplementary proposed rule, MMS asked that commenters clearly state which option best reflects their position on this issue.

Non-Arm's-Length Contracts

Industry Recommendation

The MMS should replace the proposed cumbersome, three-region approach with a menu of valuation benchmarks flexible enough to accommodate diverse transactional settings nationwide and arrive at a reasonable value of production at the lease. Such a menu should include:

- A viable tendering for sale program.
- Reliance on comparable arm's length transactions, including purchases, by a lessee, a lessee's affiliate, or other parties (if published) at or near the lease.
- A methodology to net back to the lease from an index or affiliate re-sales if deductions are provided that adequately account for factors that add value as crude oil moves downstream from the lease.

MMS Response

The primary considerations MMS has expressed for revising the Federal oil valuation rule are to ensure the public receives fair market value for its oil; to eliminate reliance on posted prices; to simplify royalty reporting, payment, collection, and auditing; and to provide certainty for both royalty payors and government.

- All of the items from the industry "menu" are included in the proposal for the Rocky

Mountains, but not in the menu format. The benchmarks are ordered according to which is most likely to reflect fair market value for the area. Lessees should not be permitted to choose among a menu of options. Such a choice would not ensure fair market value, simplify the royalty process, or provide certainty.

- Under the February 1998 proposed rule, MMS would consider a series of valuation benchmarks for valuing production that is not sold at arm's-length in the Rocky Mountain Region, where there is not a publicly available, reliable indicator of market value. Those benchmarks are: 1) tendering; 2) weighted-average of arm's-length sales and purchases in the field or area; 3) netback from an index price; and 4) an MMS-established method.

- In February 1998, for the rest of the country, MMS proposed only netback from index, the third item in the "menu" suggested at the July 22, 1998, meeting. MMS expressed the following reasons why the other benchmarks were not proposed:

__Menu__

- The Department is required to receive fair market value by setting the most appropriate valuation standard(s) for each market. Having industry choose among options for valuation will likely result in undervaluation. It will also increase complexity in the royalty process.

__Tendering__

- Tendering is an artificially-created market for the purpose of paying royalties. It does not represent how companies actually market their production and accordingly cannot represent market value. If there truly were an active, transparent, and competitive market at the lease, there would be no reason to establish a tendering program.

- Tendering is not a legitimate measure of market value where it involves only small volumes of production from company-selected properties that would be used to value large volumes of production sold to an affiliate and either resold or refined.

- Tendering is a more administratively burdensome means than index prices for valuing production not sold at arm's length. Spot prices play a major role in crude oil marketing and are readily available through price reporting services.

__Comparable Arm's-length Transactions__

- We have found through our audits that very little Federal oil is sold at arm's length.

- After a decade of experience under our current regulations, we have found the application of comparable arm's-length criteria to be costly and difficult to administer.

- Producers generally do not have access to prices paid under other producer's arm's-length contracts and we are not aware of any situations in which those prices are publicly available.

Duty to Market

Industry Recommendation

Where the starting point for valuation is away from the lease, the MMS should allow lessees to claim an administrative fee -- similar to the fee MMS charges small refiners in its set aside program.

MMS Response

- In the February 1998 proposed rule, MMS did not allow deductions from royalty value for marketing or administrative costs. It is long and clearly established law that a Federal oil and gas lessee has the obligation to market the lease production for the mutual benefit of the lessee and the lessor, without deduction for the costs of marketing. This is an implied covenant of the lease and is not unique to Federal leases. Reversing legal precedent through this rulemaking would be inappropriate. Congress could act to provide a marketing deduction.

- The administrative fee MMS charges small refiners who participate in the existing RIK program covers MMS' administrative costs of billing and accounting for the oil sold to the small refiner during the period of the contract. It is not a marketing fee. MMS does not market the oil to the small refiners, but rather makes available to them a consistent supply of oil for refining.

Transportation

Industry Recommendation

Reasonable commercial value of transportation should be the basis for calculation of transportation allowances.

Actual payments made under tariffs should be acceptable.

For lines handling multiple shippers, the payments by non-affiliated third parties should be used. In the absence of third parties, payments for comparable service areas should be used.

With the use of a tendering for sale program, the sale at the lease eliminates the issue of a transportation deduction.

MMS Response

MMS' February 1998 proposal would allow each lessee to deduct from gross proceeds or from an index price its reasonable, actual, and necessary costs of transportation.

Tariffs

- In the February 1998 proposed rule, because FERC does not have jurisdiction over crude oil pipelines on the OCS, MMS did not accept FERC tariffs as the costs of transportation to be deducted from an index price or from gross proceeds in situations where the lessee or its affiliate owns the pipeline. Congress could fix this problem by giving FERC jurisdiction.

- Under the Secretary's general rulemaking authority under 43 U.S.C. 1334, or the Secretary's rulemaking authority regarding pipeline rights-of-way on the OCS under 43 U.S.C. 1334(e), should MMS consider developing a procedure to set pipeline transportation rates and correspondingly the transportation allowances for royalty purposes?

Tendering

- Tendering does not solve the transportation issue. When a purchaser bids on tendered volumes, it must take into account the costs of transporting production away from the lease. In most cases, the purchaser will have to transport that production through a pipeline owned by the lessee and pay tariff rates that are not reviewed by FERC to assure that they are just and reasonable. A purchaser of such crude will often have to negotiate carriage rates on proprietary pipelines off the lease. A captive marketplace can result. Therefore, the price bid by the purchaser and used by the lessee to compute its royalty obligation will necessarily be discounted to reflect these lessee-established tariff rates.

- Under the OCSLA, offshore lessees are required to pay royalties on the "production saved, removed, or sold" and "production" is defined to include the "transfer of minerals to shore." Therefore, tendering at the lease offshore will not reflect the legal requirements of lessees to transfer minerals to shore.

- Under existing tendering programs, companies do not tender production from every lease in a particular field or area, but use the price received from those leases from which they do tender to value production sold to an affiliate from all of their leases in a field or area. For those leases from which they do not tender production, they must make transportation adjustments to the tendered-price to arrive at the value of production from those leases.

Third Party Rate or Comparable Costs of Service Rates

- We have found through our audits that very little oil is transported at arm's-length. Generally, lessees have joined together to build pipelines and each of them maintain an ownership interest in these pipelines. Therefore, payments by non-affiliated third parties frequently do not exist.

- Likewise, payments by third parties on other pipelines in the same area do not generally exist.

- Identifying comparable pipelines is difficult given the variations that can exist in pipelines' capacity, length, date they are placed in service, throughput, etc. Disputes would likely arise between the producer and MMS as to what constitutes a comparable cost of service, similar to what we have experienced when evaluating comparable arm's-length contracts.

Non-binding Guidance

Industry Recommendation

The MMS should simplify and clarify its valuation requirements as much as practicable.

MMS should maintain a process by which lessees can procure binding valuation determinations.

MMS Response

- In its February 1998 proposed rule, MMS did not provide for binding valuation determinations, because it cannot bind the Department. However, the Assistant Secretary has the necessary authority to make such determinations. Therefore, if requested, the Assistant Secretary may issue binding valuation determinations.

ATTACHMENT 3

SUPPLEMENTAL COMMENTS OF THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA AND THE DOMESTIC PETROLEUM COUNCIL REGARDING DEFINITION OF "GATHERING"

These supplemental comments respond to the MMS' inquiry in the Federal Register, 63 FR 38353 (July 16, 1998), regarding whether the existing definition of "gathering", as set forth in 30 C.F.R. § 206.101, which is the same as in proposed § 206.101, should be modified so that a transportation allowance can be claimed when oil production from a subsea completion is moved away from the lease to a platform where it is separated or treated. However, to ensure that an allowance is available for both oil and gas production, the gas valuation regulations, 30 C.F.R. Part 206, Subpart D, also need to be considered.

I. DISCUSSION

The definition of "gathering" found at 30 C.F.R § 206.101 and 30 C.F.R § 206.151 provides:

> "Gathering" means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM [Bureau of Land Management] or MMS OCS [Outer Continental Shelf] operations personnel for onshore and offshore leases, respectively.

The MMS wrote the 1988 definition of "gathering" at a time when it was considering and providing rules for gathering and transportation allowances on the OCS. Prior to the 1988 regulations, the Department of the Interior ("Interior") and the Courts had adopted the basic rule that, for royalty purposes, "the value to be established is generally the value of marketable gas at the lease...." *Marathon Oil Company v U.S.*, 92-99 (D. Alaska 1985), *affirmed* 807 F.2d 759 (9th Cir. 1986), *cert. denied*, 480 U.S. 940 (1987). In practice, this rule dictated that, if production was valued at a point off the lease, the United States had to bear its proportion of the cost of movement to that point. More specifically, the rule prevented federal lessees from deducting the cost of moving production to a selling point in the field, but allowed them a deduction for the cost of transportation from the field to the point of first sale. *Phillips Petroleum Company*, 109 IBLA 4, 13 (1989). Nothing in the 1988 regulations or the Comments to them suggests that, by adopting the regulatory definition of "gathering", the MMS intended to change this basic rule.[1]

---

[1]To the contrary, the 1988 version of the gas valuation regulations at 30 C.F.R.§ 206.156 provided in pertinent part:

> MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease.

The 1988 regulations define "gathering" to include a movement not only to "a central accumulation or treatment point on the lease" but also to "a central accumulation or treatment point off the lease". Nevertheless, this definition was written in a context in which "gathering", if it took place to a point "off the lease", took place to a *nearby* point, not to a distant one. It sometimes happens that, because of a shipping fairway or some other problem, it is necessary to erect the platform off the lease. But such a platform is almost always close by on an adjacent lease. There the production is accumulated and separation or treatment, if necessary, takes place. The gas valuation regulations explicitly confirm this fact. They state that "field processes . . . such as natural pressure reduction, mechanical separation, heating, cooling, dehydration and compression *normally take place on or near the lease.*" 30 C.F.R. § 206.151 (emphasis added).

In drafting the definition of gathering, the MMS did not, however, address the circumstance where production, instead of being accumulated at a nearby platform, might have to be accumulated at a subsea manifold and then transported to a point of the lease where treatment would occur. If the MMS had proposed a regulation addressing this situation, the regulation would have been subject to a notice and comment and the issues fully ventilated, but it did not.[2] For this reason, IPAA and DPC submit that the MMS should make transportation allowances available to lessees under these circumstances.

In both shallower waters and the deepwater, subsea completion technology permits the development of significant oil and gas reserves which cannot be economically exploited under traditional methods requiring the construction and installation of single or multiple structures. Subsea completion technology is safe and cost effective. However, the extent to which this technology will be employed by industry depends on the way the MMS responds to requests for transportation allowances for the movement – often over significant distances -- of the produced oil and gas from the lease to the place where separation and/or treatment occurs.

The 1988 version was revised slightly in 1996. The new regulation, which remains the same in substance, if not in form, provides in pertinent part:

> MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

2 In the new regulations which were proposed on Nov. 6, 1995, 60 Fed. Reg. 56009, but later withdrawn, the MMS provided for a transportation allowance in "deepwater" circumstances. § 206.456(3) of the proposed regulation provided as follows:

> Notwithstanding any other provisions of this sub-part, MMS may approve, upon request of the lessee, a transportation allowance for the movement of the gas from deepwater OCS leases, even if the production from the lease has not been initially separated.

API and DPC do not contend that this proposed regulation was ever binding and suggest that while the focus on novel production methodologies is appropriate, the allowance should not be restricted to deepwater leases.

Unfortunately, the MMS has refused so far to grant these requested allowances, having chosen to characterize these movements as "gathering". IPAA and DPC members believe such refusal constitutes arbitrary discrimination against a safe and cost effective technology and is inconsistent with the reasoned exercise of discretion. *CNG Producing Company*, MMS-96-0370-OCS, currently pending on appeal before the Interior Board of Land Appeals ("Board"), illustrates the problem.

In this case, the Director denied CNG an allowance for transportation of production for the twenty-five miles from the deepwater (2000+ feet) "Popeye" field, located in Green Canyon Block 116 ("GC-116") to a tie-in on the OCS at the Cougar Platform located in South Timbalier Block 300A ("ST-300A").

There is no platform at or near GC-116 because, absent a very large discovery of reserves, a platform could not be built without prohibitive expense. Project economics mandated that CNG and the other Popeye working interest owners install a subsea manifold at GC-116 in lieu of a platform. The production from wells at GC-116 is accumulated at this subsea manifold, where it is injected into two six-inch looped lines and then transported twenty-five miles to ST-300A. There the production is separated, dehydrated, and metered and then further transported to the shore.[3]

Based on the definition of "gathering" at 30 C.F.R. § 206.151, which definition was adopted in 1988, and on the answers to four questions found in the MMS Payor Handbook, the Director concluded that CNG's movement of production in question was "gathering" and not "transportation". She then ruled that, because "gathering is considered part of placing lease production in marketable condition", CNG is required to bear the entire cost of transporting production from GC-116 to ST-300A.

If the Popeye field had been located in shallower waters, a platform would have been erected at or near the field. The production would have been gathered to that platform and separated and measured there. Then it would have been transported through a line to another platform where it would be injected into a transmission line. In this context, CNG would have been permitted a transportation allowance for the line.

However, due to the characteristics of the reserves and the water depth, a subsea manifold was installed instead of a platform on or near the lease. This required that separation, dehydration, and measurement occur some twenty-five miles nearer the shore instead of at the field. But these factors do not mean that the transportation allowance should have been denied. To the contrary, to permit a transportation allowance in the first instance but deny one in the second case constitutes arbitrary discrimination against the use of subsea completion technology.

---

[3]CNG did not seek an allowance for the costs of dehydration or separation or any other treatment of production from GC-116 nor an allowance for the cost of the subsea manifold.

IPAA and DPC urge the MMS to take this opportunity to eliminate such discrimination. Indeed, Interior has acted on several occasions involving functionally analogous situations to avoid similarly arbitrary results. In *Exxon Company, U.S.A.*, MMS-VSD-OG:93-0075 (December 29, 1994), the Chief, MMS Valuation and Standards Division, considered Exxon's request for a transportation allowance for the cost of moving oil through its "Grand Isle System" of pipelines. Exxon used its Grand Isle System to transport oil from a number of platforms to its Grand Isle terminal.

Prior to issuing her final ruling, the Chief made a number of preliminary findings, which closely resemble those made in *CNG Producing Company*. Specifically, the Chief found that (1) the oil moving through the pipeline system was not in marketable condition, (2) the pipeline system was located upstream of the separation and treatment point, and (3) the pipeline system met the definition of a gathering system. The Chief then went on to cite the general rule that "(a) transportation allowance is not permitted for oil that is not in marketable condition" and noted that "(t)o apply the strictest definition of the regulations, policy and past court decisions would mean that all costs incurred by Exxon to move production through the Grand Isle system would be disallowed." *Id.* at 3.

The Chief, however, decided to depart from the above noted standards and invoked Interior's discretionary authority to determine the factors that are to be used in computing a transportation allowance for royalty purposes. *Id.* at 4. Rather than accept the result dictated by application of the existing rules, the Chief instead based her ruling on the actual function being served by the pipelines in question. The Chief granted Exxon a transportation allowance for movement of oil production through the Grand Isle System because it would be necessary for Exxon to move the production over the distance in question under any circumstances. *Id.*

In *Shell Offshore, Inc.*, 142 IBLA 71 (1997), the Board, recognizing special circumstances, reversed a decision of the Director and held that, although a lessee had never before obtained a transportation allowance for costs incurred in the construction of a platform, nevertheless Shell should under the circumstances be permitted a transportation allowance for a portion of such costs. The Board based its decision on the finding that Shell incurred additional expenses for the platform due to the fact that the platform would have been smaller and less costly "if the compressor and other transportation machinery were not required to be there." The Board stated that, unlike the deepwater suspension platform constructed by Shell, platforms built on the OCS are grounded on the ocean floor and do not need to be constructed and designed specifically to support an associated transportation facility. Accordingly, the Board found that:

> Shell is entitled to include the cost expended on the Auger platform needed to buoy the compressor and other transportation equipment as a reasonable actual transportation cost under 30 C.F.R. § 206.157 (b) (2).

In *Exxon Corp.*, 118 IBLA 221 (1991), Exxon sought a transportation allowance for gas produced from its wells on three federally owned units. Because of economic and environmental concerns and at the recommendation of the BLM and of the Forest Service, Exxon did not separate and condition the product for market in the field but at the Shute Creek plant some 40 miles distant. Exxon not only separated the gas at Shute Creek, it also dehydrated the gas there. To avoid the expense of building a very much more expensive pipeline, Exxon also dehydrated the gas near the field and then transported it the 40 miles to Shute Creek. Notwithstanding that the facilities in question were upstream of the separation point, the Board granted Exxon a transportation allowance for the 40 miles of pipeline. Further, notwithstanding that the cost of dehydration is ordinarily considered part of the cost of marketing, the Board granted Exxon a transportation allowance for the cost of dehydration.[4] The Board did so because the purpose of the dehydration was not to place the gas in marketable condition but to transport it to the Shute Creek plant.

The Board reached its result in *Exxon* on account of circumstances directly analogous to those present when subsea completion technology is employed. Under normal circumstances, Exxon would have built its separation and treatment facilities near the field. Instead Exxon had to "transport" the gas some 40 miles to the Shute Creek plant prior to separation and treatment.

The stark contrast between the granting of allowances in the above circumstances and their denial in the subsea completion context is not defensible. The use of subsea completion technology is clearly in the public interest. Discrimination against this beneficial technology through the denial of transportation allowances is arbitrary and should be eliminated.

II. RECOMMENDED ACTION.

In order to remedy the current discriminatory situation, IPAA and DPC urge the MMS to exercise its administrative discretion by issuing on an expedited basis an interpretive rule applicable to its existing regulations and with retroactive effect providing that a transportation allowance will be granted the lessee when production from a subsea completion is moved away from the lease to a structure where separation or treatment is performed. The allowance should be available for production moving from a subsea completion in any water depth.

Further, in addition to the issuing the foregoing interpretive rule, IPAA and DPC agree with the MMS that the regulations should be modified to contemplate subsea completion operations. Unfortunately, the comment period is so abbreviated that IPAA and DPC have been unable to receive member approval for specific proposed regulatory text. Were a further extension of time for comment on this matter to be provided, IPAA and DPC are confident that such text would receive

---

[4] In *Exxon*, the Board recognized that the initial dehydration in the field was in reality a cost of transporting the gas to the plant, rather than a cost of placing it in marketable condition.

membership approval and be provided to the MMS.

IPAA and DPC appreciate the MMS' willingness to reconsider its position on an important matter of great interest to independent producers. Both associations look forward to the opportunity for further input.